EXECUTIVE SUMMARY

On behalf of the California Energy Commission (CEC) and the Electrical Power Research Institute (EPRI) Ken Henderson of HDR Engineering conducted a "walk-through" energy evaluation of Union Sanitation District's wastewater treatment plant. In 1999, the plant paid $1,007,422 for 18,184,050 kWh of electricity. This results in an average of 5.54 ¢/kWh including demand charge and miscellaneous fees. During this time the plant also cogenerated 1,551,561 kWh electricity, which gives a total power consumption of 19,735,611 kWh. This power, used to treat approximately 10,975 Mgal, yields a specific energy consumption of 1,657 kWh/Mgal. This is comparatively low for secondary activated sludge treatment plants. Typical secondary wastewater treatment plants consume 1,800 to 2,500 kWh/Mgal treated. A snapshot of energy for the plant is shown in Table 1-1.

Table 1-1. USD Energy Snapshot for 1999.

Plant Flow	10,975 Mgal
Average Daily Flow	30 mgd
Total Electricity Cost (5.54¢/kWh)	$1,007,422
Total Identified Savings for this Report	$338,540 (33%)
Electricity Usage	
Purchased Electricity	18,184,050 kWh
Generated On-Site	1,551,561 kWh
Unit Energy Consumption	1,657 kWh/Mgal
Billing Demand Range	2,630 kW – 3,200 kW

The information obtained from the energy distribution along with the data gathered during the site visit aided in identifying potential energy conservation measures (ECMs). The ECMs summarized in Table 1-2 are estimated to save approximately $335,440 annually and should be considered for implementation.

OBSERVATIONS & RECOMMENDATIONS

Observations

1. Unit energy consumption is 1,657 kWh/Mgal, which is commendably low for an activated sludge treatment plant.
2. Plant staff has, on their own initiative, identified measures that could reduce power consumption.

Table 1-2 Summary of ECMs

ECM	Energy Savings (kWh)	Yearly Cost Savings	Potential Rebates	Estimated Capital Cost	Simple Payback (years)	Recommended
1. Run Cogen full-time	4,600,000 kWh 600 kW	$254,000	$180,000	$205,000	1.1	YES
2. Reduce Digester Mixing	657,000 kWh 75 kW	$36,400	$22,500	$15,000	<1	YES
3. Reduce Lighting	65,700 kWh 10 kW	$3,640	$7,000	$10,000	<1	YES
4. Install an Energy Management Program	0 kWh 180 kW	$8,500	Unknown	$10,000	1.2	YES
5. Modify NPW System	657,000 kWh 7 kW	$36,000	$81,630	$42,000	<1	YES
Total of Recommended ECMs		**$338,540**	**$291,130**	**$282,000**	**<1**	

3. PG&E’s proposed rate change on the E-20 rate schedule should decrease the annual cost for power. However, if real-time pricing schedules are implemented, the cost could increase significantly.
4. Contaminants in the digester gas damage the cogeneration system, increasing maintenance and purchased power costs.
5. The cogeneration system was used for only 4 months in 1999. When operational it reduces purchased power by approximately 20 percent.

Recommendations

1. Implement recommended ECMs.
2. Apply for PG&E’s rebate program - 9¢/kWh for first year savings.
3. Initiate a study on the cogeneration system to evaluate alternatives to improve reliability.
4. Establish an energy champion at the plant to monitor energy efficiency and implement energy conservation projects.
5. Apply to the California Energy Commission for grant funding program established under AB 970.

INTRODUCTION

This study is a joint effort between the Electric Power Research Institute (EPRI) and the California Energy Commission (CEC). Its purpose is to identify potential conservation measures that could reduce the plant's energy consumption or electrotechnologies that could improve the treatment process. HDR Engineering conducted the study as a consultant to both EPRI and the CEC.

PLANT DESCRIPTION

The wastewater plant treats an annual average flow of 30 mgd. The liquid treatment process includes climbing screens, vortex grit removal, primary sedimentation basins, aeration basins, secondary clarifiers, and chlorine disinfection. The solids process includes anaerobic digestion, gravity thickeners, gravity belt thickening, belt filter press dewatering, and landfill disposal. Figure 2-1 and 2-2 are schematics of the liquid and solids treatment processes.

SCOPE OF WORK

HDR Engineering performed a "walk-through" energy evaluation of Union Sanitation District's treatment plant. On August 15, 2000, Dave Stoops gave Ken Henderson of HDR a tour of the facilities. Measures to reduce energy costs were identified from the information gathered during the site visit and are summarized in this report.

ACCURACY

This report is based on a "walk through" evaluation of Union Sanitation District's wastewater treatment plant. It is a planning level document intended to identify energy conservation measures (ECMs) and electrotechnologies that could benefit plant operations. The recommended projects should be implemented only after conducting pre-design/design level analysis, which is beyond the scope of this report. The accuracy of all cost and savings estimates are ±25 percent. Construction cost estimates assume basic installations and are made for each idea individually. The total cost for engineering and construction services can vary depending on the combination of ideas selected for installation, the amount of instrumentation and control interfaces desired, the schedule of construction, and the level of bidding and construction services requested.

Figure 2-1 Liquid Process Schematic

Figure 2-2 Biosolids Process Schematic

ACKNOWLEDGEMENTS

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Union Sanitation District:

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Ray Ehrhard

California Energy Commission

Mike Hartley

ENERGY CONSUMPTION, ELECTRIC RATE SCHEDULE, AND REBATE PROGRAMS

The total energy purchased in 1999 was determined from the electrical billing history. During this time the plant paid $1,007,442 for 18,184,050 kWh of electricity. This results in an average of 5.54 ¢/kWh including demand charges and miscellaneous fees.

The District purchases electrical power from Pacific Gas & Electric Company under rate schedule E-20P. PG&E has two primary charges for electrical power under this schedule. The first is for *demand*, which is the power supplied by the electric utility measured in kilowatts (kW). The second, *energy*, is the quantity of power used measured in kilowatt hours (kWh). Rate Schedule E-20P is a Time-of-Use (TOU) rate schedule that bills for both energy and demand based on the time of day it is used. Under the E-20P, 1 kW of power used continuously for a year costs an average of 6.52 ¢/kWh including demand charges. The cost for power under the firm, E-20P rate schedule as of March 2000 is summarize below in Table 3-1.

Table 3-1 Rate Schedule E-20P

	Period	Rate	Demand Charge
Summer	On-Peak	$0.06271/kWh	$11.80/kW
	Partial-Peak	$0.04868/kWh	$2.65/kW
	Off-Peak	$0.04683/kWh	$2.65/kW
Winter	Partial-Peak	$0.05700/kWh	$2.55/kW
	Off-Peak	$0.04782/kWh	$2.55/kW

The rates that the electric utilities have been charging were frozen by the PUC as a part of the transition to deregulation. PG&E has recently applied to the Public Utility Commission to change the rate and structure of schedule E-20 to recoup debt. The proposed change would effect the cost per kilowatt-hour. The cost per kilowatt-hour will varying widely based on supply and demand of electrical power. Prices ranging from 10¢ to 25¢ per kilowatt-hour for the energy portion of the bill alone could occur during peak summer months. It is anticipated that demand charges will be changed to a flat rate. This could adversely affect load management practices that take advantage of the low demand charges in the off-peak hours. However, with real-time pricing the energy charge should also drop during the off-peak hours. This should help mitigate the loss of savings once obtained through low demand charges. The net result for the District is expected to be higher electric bills in the summer and lower bills in the winter.

A graph of the plant's 1999 annual energy use was assembled for evaluation. As seen in Figure 3-1, the flow rate through the plant is fairly consistent through the year. However, electrical demand and energy appear to increase during wet weather. The increase in demand is likely due to periodic storms that temporarily increase the amount of pumping. The cause for the increase in energy consumption is uncertain. The amount of energy used in treatment for most plants will typically reflect the monthly flow. Activities that force deviations from this trend are difficult to determine but can result from seasonal changes to plant operations.

The staff has done a good job in minimizing on-peak demand. On average, the on-peak demand is approximately 1,000 kW less than the part- and off-peak demand. This effort minimizes demand charges. If PG&E's proposed rate change is approved the demand charge will be billed at a flat rate. This will eliminate some of the cost savings achieved through load shifting. The benefits of using an Energy Management System (EMS) to help control costs are discussed in Section 5.

An evaluation of the major electrical loads categorized by process indicates that aeration uses approximately 40 percent on the total power. This is followed by the effluent pumping and odor control, which use approximately 23 percent and 12 percent, respectively. Figure 3-2 shows the energy distribution within the treatment plant and the data is in Appendix A.

PG&E has a very attractive rebate program for 2000. Incentives of up to $1.5 million per customer and $400,000 per location are possible. Rebates are equivalent to the first year savings in kWh X 9¢ not to exceed half of the project cost. All project with the exception of cogeneration systems are qualified. The District should contact their PG&E representative for more information prior to implementing any conservation measures. The CEC is administering a grant fund program initiated through AB970. This program offers $300 per kW of load removed from service and $200 per kW of load shifted to off-peak hours. This program is open to all projects that can be constructed and operational by June 1, 2001. Funds should be available beyond June but at a lower amount.

Figure 3-1 1999 energy profile

Figure 3-2 Energy Distribution

ENERGY CONSERVATION MEASURES

The ECMs listed below were developed from information collected at the site visit and from evaluation of historical plant data. Unless otherwise noted, savings for the ECMs was determined using an average energy cost of 5.54 ¢/kWh, which includes demand charges. Potential rebates from PG&E and the California Energy Commission (CEC) are also included. PG&E offer 9 ¢/kWh saved in the first year not to exceed half of the project cost (cogeneration projects are not included). The CEC provides grant funds under AB970, which pays $300 per kW of demand removed from service and $200 per kW of demand shifted from on-peak hours. Calculations are in Appendix B.

ECM 1	Run Cogen Full-Time
ECM 2	Reduce Digester Mixing
ECM 3	Reduce Lighting
ECM 4	Automate DO Control System
ECM 5	Install an Energy Management Program
ECM 6	Modify NPW System

ECM 1 SUMMARY SHEET

RUN COGEN FULL-TIME

Existing Conditions—

Digester gas is used to fuel the cogeneration system. the system generate approximately 600 kW and reduce the amount of power purchased by an average of 20 percent. Contaminants in the gas cause mechanical failure, which increase O&M costs and impact the cost of purchased power.

Proposed Change—

Repair cogeneration system and operate full-time during on-peak and partial-peak hours. Install equipment to clean the digester gas and remove the siloxane. Move siloxane equipment to new cogen equipment when built.

Benefit or Effect on Operations—

The value of digester gas has increased with the rising cost of natural gas and electrical power when purchased on the hourly market. This makes the operation of the cogeneration system more feasible. Evaluate various methods of removing siloxane before running the system.

Cost Analysis—

Demand Savings:	600 kW
Energy Savings:	+4,600,000 kWh/yr
Annual Operating Cost Savings:	$254,000
Capital Cost for Changes:	$205,000
Potential PG&E Rebate:	Not available for cogen
Potential CEC Rebate:	$180,000 (600 kW x $300/kW)
Simple Payback (w/ rebate):	1.1 years
Recommended:	YES

ECM 2 SUMMARY SHEET

REDUCE DIGESTER MIXING

Existing Conditions—

The digester receive mixing from both the mixing pumps and the heat recirculation pumps. Both run continuously.

Proposed Change—

Modify the SCADA system programming to run the mixing pumps intermittently with not more than two pumps running at one time. Run each pump approximately 8 hour per day or as necessary to maintain treatment.

Effect on Operations—

None anticipated. Mixing is only needed to prevent stratification. The heat recirculation pumps will provide a small amount of mixing when the mixing pumps are off.

Cost Analysis—

Demand Savings:	75 kW
Energy Savings:	657,000
Annual Operating Cost Savings:	$36,400
Capital Cost for Changes:	$15,000
Potential PG&E Rebate:	$7,500 (half of cost)
Potential CEC Rebate:	$15,000
Simple Payback (w/ rebate):	<1 year
Recommended:	YES

ECM 3 SUMMARY SHEET

REDUCE LIGHTING

Existing Conditions—

The HID indoor lights left on when the room are unoccupied.

Proposed Change—

Modify lighting to include additional light switches, occupancy sensors, or timers as appropriate to reduce lighting. Include natural lighting (skylights and windows) where able. Install skylights in all new construction.

Benefit or Effect on Operations—

Evaluate each application to allow for safety of personnel. Fast strike light fixtures may be needed for convenience. Leave sufficient lighting in each room to prevent total darkness.

Cost Analysis—

Demand Savings:	10 kW (100 lights @ 100 W ea. off 75% of the time)
Energy Savings:	65,700 kWh
Annual Operating Cost Savings:	$3,640
Capital Cost for Changes:	$10,000
Potential PG&E Rebate:	$5,000 (half of cost)
Potential CEC Rebate:	$2,000
Simple Payback (w/ rebate):	<1 year
Recommended:	YES

ECM 4 SUMMARY SHEET

INSTALL AN ENERGY MANAGEMENT PROGRAM

Existing Conditions—

Electrical demand varies from 2,600 to 3,200 kW. The SCADA system already receives electrical data from the plant MCCs and has a load shedding strategy in place.

Proposed Change—

Program the SCADA system to alarm on high electrical demand. Use the existing signals from the MCCs together with new user setpoints that allow operators to target a demand level. Use the load shedding strategy and cogeneration to keep demand below the setpoint.

Benefit or Effect on Operations—

An energy management system provides real-time information needed to control demand. Control of the treatment process is still at the operators discretion.

Cost Analysis—

Demand Savings:	180 kW (10% of avg. kW, 4 months per year)
Energy Savings:	0 kWh/yr
Annual Operating Cost Savings:	$8,500
Capital Cost for Changes:	$10,000
Potential PG&E Rebate:	Unknown*
Potential CEC Rebate:	Unknown*
Simple Payback (w/ rebate):	1.2 years
Recommended:	YES

*A rebate might be available as custom project.

ECM 5 SUMMARY SHEET

MODIFY NPW SYSTEM

Existing Conditions—

The NPW system operates at approximately 114 psi. we observed four NPW pumps operating on November 6, 2000, each rated at 650 gpm. Only 750 gpm was leaving the building. Operators indicate that 2 or 3 pumps normally operate. Four pumps in operation is unusual. The plant NPW piping is undersized and not looped properly, which forces operation at higher pressure.

Proposed Change—

The plant piping system is being modified to reduce flow restrictions. This could allow operation at a lower pressure. We suggest installing a VFD on two of the NPW pumps to allow automatic pressure control of the system. System could be set a 75 psi and the VFD would control pump speed to maintain system pressure. The NPW system should be investigated to reduce all unnecessary flows and eliminate potential recirculation at the NPW strainer. It may be possible to operate with at least one less pump.

Benefit or Effect on Operations—

Lower operating pressure could reduce pipe breakage and leaks.

Cost Analysis—

Demand Savings:	75 kW
Energy Savings:	657,000 kWh/yr
Annual Operating Cost Savings:	$36,000
Capital Cost for Changes:	$42,000
Potential PG&E Rebate:	$59,130
Potential CEC Rebate:	$22,500
Simple Payback (w/ rebate):	immediate
Recommended:	YES

PROCESS DISCUSSION

HEADWORKS

Wastewater enters the plant under gravity flow. The waste stream is metered in the headworks building prior to passing through climbing barscreens. The barscreens are automatic and consume little energy. On the day of the site visit, the headworks building was unoccupied yet it was completely lit inside with high pressure lights (HPS). Turning off all but a few lights would reduce the energy consumed while still proving enough light for safety.

PRIMARY CLARIFIERS

The District has square primary sedimentation basins. Biosolids collected from the primary clarifiers are discharged to the solids processing facility. The removal of efficiency for BOD and TSS is good. Although no energy conservation measures were identified for the primary clarifiers, it was noted that the buildings enclosing the clarifiers was completely lit while unoccupied. Turning off a majority of the lights, leaving enough on for safety, would reduce the amount of power consumed.

This perhaps could be most easily accomplished be adding a new switch with one or two new lights or re-wiring the existing circuit to incorporate additional lights switches.

GRIT REMOVAL

Grit removal occurs after the primary clarifiers. Primary biosolids are sent to the solids handling facility where grit is removed. No energy conservation measures were identified for this process.

AERATION BASINS

The aeration basins use fine bubble diffusers. The amount of air supplied to the basins is manually controlled based on dissolved oxygen (DO) readings. The DO readings are already connected to the plant SCADA system, which simplifies the implementation of automated DO control. Plant staff has identified this opportunity and is proceeding to have this measure implemented.

SECONDARY CLARIFIERS

Mixed liquor from the aeration basins is discharged to the secondary clarifiers. An evaluation of the secondary clarifiers is currently being conducted to determine methods to improve performance. Therefore, no energy conservation measures were identified for the secondary clarifiers in this report.

DISINFECTION

The plant uses chlorine for disinfection. The process is working well and no energy conservation measures were identified.

EFFLUENT PUMPING

The plant's effluent pumping station is run by the East Bay Discharge Authority (EBDA). The station has three 200 hp and two 125 hp pumps that operate with VFDs to maintain wetwell level. No energy conservation measures are recommended.

NO. 3 WATER SYSTEM

The No. 3 water system appears to be operating without pump speed control at approximately 114 psi. This is a high pressure for a No. 3 water system. We believe that the pressure could be reduced to approximately 75 to 85 psi, which could decrease the power by as much as 30 percent. If higher pressure is needed for washing basins, then the setpoint could be temporarily increased for these activities. Pressure control using VFDs should be installed.

SOLIDS PROCESSING

The plant has six anaerobic digesters. Each digester has a dedicated axial flow pump for mixing and heat recirculation pump. There is a total of 190 hp used by the mixing pumps alone. Digesters only require mixing to prevent stratification. Additional mixing has shown to have negligible effects on digestion or gas production. Proving intermittent mixing by sequencing the mixing pumps with timers could reduce the electrical demand by approximately 75 kW (100 hp). This could reduce energy consumption by approximately 657,000 kWh, saving $36,400 annually. Although the heat recirculation pumps could also be run intermittently, the potential for plugging the heat exchangers makes this idea impractical.

COGENERATION

Th plant's cogeneration system produces 600 kW of power. The system runs entirely off of digester gas, which is considered to be a dirty fuel. Consequently, the cogeneration system as been down for maintenance due to failures caused by the contaminants in the fuel. When the system is operational it decrease the amount of power purchased by approximately 20 percent. If the system were able to run continuously it could generate over 460,000 kWh per year savings over $250,000 annually.

ODOR CONTROL

The City of Union City initiated a project to eliminate odor complaints. Twelve odor scrubbers were installed that run continuously. Each scrubber has a fan, which range in size from 15 to 20 hp. A few of the fans have dual speed motors that provides some control over the air flow rate. Some of the scrubbers also fulfill the function of an air handling unit in that they are the sole equipment used for air changes in a building.

ENERGY MANAGEMENT

The ability to monitor demand in real-time could assist in decreasing demand. Awareness of when the peak is occurring would provide operators an opportunity to better manage demand and reduce costs. An energy management system could easily be incorporated into the plant's SCADA system. The system already receives energy information from MCCs in the plant. In stalling the hardware needed to collect this information is the largest cost in stalling any Energy Management System (EMS). Adding the necessary programming to process the energy information and provide user set alarms for electrical demand would provide a basic EMS. Automated load shedding could also be incorporated, the information of which is also already received by the plant's SCADA.

OBSERVATIONS & RECOMMENDATIONS

Observations

1. Unit energy consumption is 1,657 kWh/Mgal, which is commendably low for an activated sludge treatment plant.

2. Plant staff has, on their own initiative, identified a few measures that could reduce power consumption.

3. PG&E's proposed rate change on the E-20 rate schedule should decrease the annual cost for power. However, if real-time pricing schedules are implemented, the cost could increase significantly.

4. Contaminants in the digester gas damage the cogeneration system, increasing maintenance and purchased power costs.

5. The cogeneration system was used for only 4 months in 1999. When operational it reduces purchased power by approximately 20 percent

Recommendations

1. Implement recommended ECMs.

2. Apply for PG&E's rebate program - 9¢/kWh for first year savings.

3. Initiate a study on the cogeneration system to evaluate alternatives to improve reliability.

4. Establish an energy champion at the plant to monitor energy efficiency and implement energy conservation projects.

5. Apply to the California Energy Commission for grant funding program established under AB 970.

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